REVIEW OF POTENTIAL ENERGY GENERATION CEDAR HILLS LANDFILL TECHNOLOGIES

KING COUNTY DEPARTMENT OF NATURAL RESOURCES
SOLID WASTE DIVISION

MARCH 2001

R·W·BECK

GLOSSARY

Availability The percentage of hours per year a power generation facility can reliability be expected to operate at rated output.

Base Loaded The condition where a power generator operates full capacity 24 hours per day, seven days per week, uninterrupted for the duration of a power sales contract or agreement.

Btu (British thermal unit) A unit of heat energy equal to the heat needed to raise the temperature of 1 pound of air-free water from 60° to 61°F at a constant pressure of 1 standard atmosphere.

Carbon Monoxide (CO) A colorless, odorless gas resulting from the incomplete oxidation of carbon.

Catalytic Combuster A system containing a chemical reactant which enhances the reduction of chemical bonds in harmful combustion byproducts.

CF (Capacity Factor) The actual percentage of hours per year, a power generation facility operates

CO see carbon monoxide. Abbreviation for carbon monoxide.

Combustion Turbines (CT) A heat engine that converts energy of fuel into work by using compressed, hot gas as the working medium and that usually delivers its mechanical output through a rotation shaft. Also known as gas turbine.

Command and Control A type of electronic guidance wherein signals or pulses sent out by an operator operates and monitors generating units from a remote location.

Commercial Status Whether a power generation technology is considered experimental, or proven in the marketplace, capable of being publicly financed and performing as predicted.

Compressed Natural Gas A naturally occurring gas, stored under pressure, containing mostly methane and ethane.

Condensate Liquid resulting from condensation of water vapor.

Control A means or device to direct and regulate a process or sequence of events.

DCS (Distributed Control System) Central computer system for monitoring, annunciation, control and documentation of a power generation or process plant.

Expansion Turbine Steam turbine or high pressure post-combustor sections of a combustion turbine.

FGR (Flue Gas Recirculation)

Fuel Cell A cell that converts chemical energy directly into electric energy, with electric power being produced as a part of a chemical reaction between the electrolyte and Hydrogen fuel.

Gas-Fired Engine Generators Stationary internal combustion-based engines using a multiple crankshaft-piston arrangement to electric produce power.

Heat Rates An expression the conversion efficiency of a thermal power plat or engine, as heat input per unit of work output; for example. Btu/kWhr.

HHV (Higher Heating Value) The energy content of a fuel excluding the latent heat contained in exhaust products.

High-Btu Gas The product of a thermal-mechanical-chemical process that removes carbon dioxide and other contaminants from LFG. Similar to Natural Gas.

(IC) Engines (see Gas Fired engine generators)

kV (kilovolt) A unit of potential difference equal to 1000 volts. Abbreviated kV.

LFG (Landfill Gas) Product of microbial decomposition of municipal solid waste with a landfill.

Life-Cycle Cost A statement of comparative project value over a period of time, usually expressed as the present value of all the costs and revenues, plus debt amortization for a particular project or alternative.

LNG (Liquefied natural gas)

Methane (CH_4) An odorless, colorless and tasteless gas that can be used as a fuel.

Microturbines Combustion turbine, usually in the 50 to 300 Kw output range.

Monitoring Instrumentation used to measure continuously or at intervals a condition that must be kept within prescribed limits.

MW (megawatt) A unit of power, equal to 1,000,000 watts. Abbreviated MW.

MWH A quantity of electricity equal to one megawatt for a period of one hour.

NOx (Nitrogen oxides) Various harmful oxides of nitrogen formed in high temperature combustion processes.

NMOC (Non Methane Organic Compound) Any number of organic compounds found in landfill gas, see VOC.

Otto Heat Cycle (Otto Cycle) A thermodynamic cycle for the conversion of heat into work, consisting of two isentropic phases interspersed between two constant-volume phases. Also commonly referred to as spark-ignition internal combustion cycle.

Pipeline Quality Gas See High Btu Gas

PF (Plant Capacity Factor) The ratio of the average power load of an electric power plant to its rated capacity.

PPMV (Parts per million volumetric)

Prime Mover The central component of a power generation process, typically the device that generates the angular momentum or driven rotating shaft, usually connected to a electric generator.

Rankine Cycle An ideal thermodynamic cycle consisting of heat addition at constant pressure, isentropic expansion, heat rejection at constant pressure, and isentropic compression; used as an ideal standard for the performance of heat-engine and heat-pump installations operating with a condensable vapor as the working fluid, such as a steam power plant. Also known as steam cycle.

SCADA (Supervisory Control and Data Acquisition) A computer networked data communications system typically used by utility managers to monitor one or more power generators, or electrical distribution systems.

SCR (Selective Catalytic Reduction) A means of reducing NO_x emissions by introducing a catalyst into the flue gas.

SOx (Sulfur oxides) Various harmful oxides of sulfur formed in combustion processes in which sulfur is contained within the fuel.

Var/Kvar (volt-ampere reactive) A characteristic of Alternating Current (AC) that is measured and controlled. Used to evaluate (KW/KVA) quality/PF. The unit of reactive power in the International System; it is equal to the reactive power in circuit carrying a sinusoidal current when the product of the root-mean-square value of the current, expressed in amperes, and by the sine of the phase angel between the voltage and the current, equals 1. Abbreviated var. Also know as reactive volt-ampere.

VOCs (Volatile Organic Compounds) Numerous chlorinated and organic hydrocarbon and compounds known to be highly reactive or toxic to humans and wildlife.

SECTION 1
INTRODUCTION AND SUMMARY OF ASSUMPTIONS AND CONCLUSIONS

INTRODUCTION

The King County Department of Natural Resources Solid Waste Division ("Division") has long considered development of facilities to recover energy from landfill gas ("LFG") generated at the Cedar Hills Landfill. Up to this point however, project economics were unfavorable due to the relatively low price for electricity and natural gas in the region. Recent run-up in energy prices and advances in technology have improved project feasibility, and the Division is again considering energy recovery. R.W. Beck was hired to conduct an updated evaluation of the range of technologies that may be suitable for use at Cedar Hills. This report describes R. W. Beck's preliminary evaluation of these technologies.

The report is organized into five sections as follows:

Section 1 – Introduction and summary of findings

Section 2 – A description of the project concept and overview of technologies: A summary of costs, efficiency, emissions performance and commercial status of available technologies

Section 3 – Landfill gas energy use: a description of landfill gas characteristics and pretreatment requirements

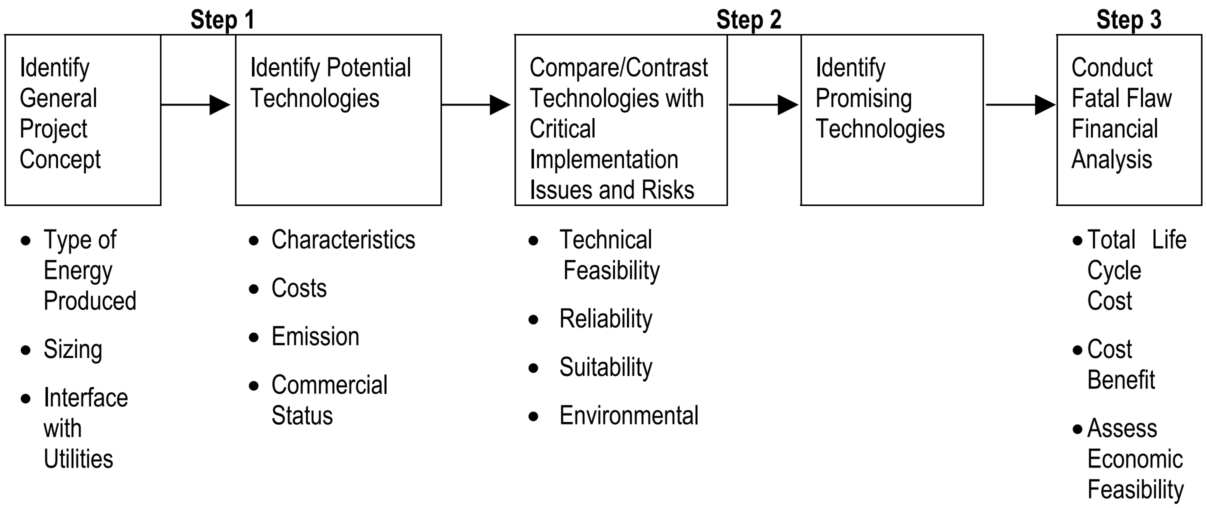
Section 4 – Evaluation of options: A general assessment of the relative merits of alternative technologies and identification of the most promising options

Section 5 – Financial assessment: A life-cycle cost comparison of the most promising technology options

Appendix A – Life cycle cost analyses

Appendix B – Description of landfill gas characteristics and pretreatment

The evaluation in this report is conducted in a stepwise fashion as shown below:



SUMMARY OF ASSUMPTIONS

The current situation relative to energy pricing, technology and regulatory and legislative constraints is very fluid. In preparing the conclusions that follow, we have made certain assumptions with respect to conditions that may exist, or events which may occur in the future. Key among these is that, based on previous studies, the Cedar Hills Landfill will produce at least 14 million cubic feet per day of landfill gas through the 15-year economic life of the project. The energy content of the landfill gas is approximately 450 BTU per cubic foot Higher Heating Value (HHV).

For purposes of the economic evaluation, we have assumed a base case electricity market value of 4.5 cents per Kilowatt hour (KWh) and a high electricity market value of 6 cents per KWh. There is no major energy market near the landfill that could directly purchase preconditioned landfill gas, and we have assumed that electricity from the project will be delivered to the Puget Sound Energy system. Finally, we have assumed that there are no major permitting obstacles to construction and operation of a facility at the Cedar Hills site.

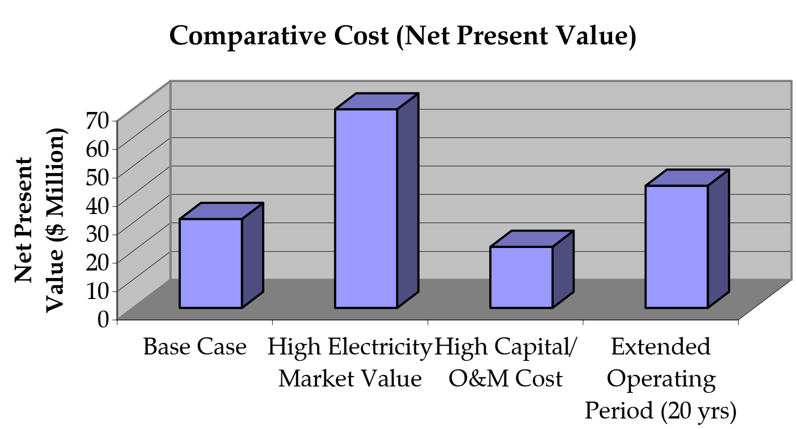
CONCLUSIONS

On the basis of our review of the possible generation of energy from landfill gas at the Cedar Hills Landfill, we offer the following conclusions:

1. Of the technologies considered, only combustion turbines, boiler steam turbine combination, and gas powered reciprocating engine generators have proven commercial operation on similar projects. Refer to Table 1-1 for a general summary of our review of technologies. Table 1-2 provides a description of each technology considered.

2. Gas turbines and steam turbines are the preferred electric power generation configurations.
3. Of these technologies, combustion turbines and a boiler steam turbine combination are available in capacities suitable for the expected output of a power generation facility at the Cedar Hills Regional Landfill. Commercially available gas powered reciprocating engine generators are of smaller capacity than would be optimum for the Cedar Hills project.
4. The results of the economic evaluation for the base case and all sensitivity cases show a positive net present value indicating the project is economically feasible. The results are as follows:

Scenario	Capacity	Operating Period (years)	Capital Cost ($ Million)	O&M $/KWh	Power $/KWh	Net Present Value ($ Million)
Base Case	22 MW	15	20	1.5	4.5	31.3
High Electricity Market Value	22 MW	15	20	1.5	6.5	69.9
High Capital/ O&M Cost	22 MW	15	24	1.8	4.5	21.5
Extended Operating Period (20 yrs)	22 MW	20	20	1.5	4.5	43.0
All costs are in 2001 dollars.						



5. Micro-turbines are impractical because of their small size.
6. Fuel cells are not yet commercially proven and may not be technically feasible due to gas quality requirements.

7. Clean fuel production appears to have promise, however we are not aware that this technology has achieved commercial operation at a location similar to Cedar Hills.
8. Project economic feasibility will depend on a number of factors:
   - Market price for electricity
   - Project startup date
   - Availability of prime mover(s)
9. There may be an opportunity to obtain federal tax credits from the project through a third party participant. Eligibility will depend on the timing of development and commissioning of the existing landfill gas collection system and the extent which the existing gas system was financed through tax-exempt bonds. If the project is eligible, it will be necessary to establish the appropriate contractual arrangements so that the County can benefit from such incentives.
10. The value of electricity will depend on a combination of factors including total generating capacity, schedule for development of needed sources, weather, and on-going hedge strategies of users. An analysis of these factors is beyond the scope of this project. Energy pricing analysis is required to confirm the assumption used in this report and to identify the preferred approach to marketing electricity generated by the project.
11. Ownership and contracting arrangements that best meet the needs of the project may vary.
12. The current high market price for electricity is expected to ease in the next several years. A project which can be brought on line before that time could achieve significant economic benefit. For this reason, the Division should explore ways to bring the project on-line as soon as practical.
13. This report did not review zoning, environmental permitting or State Environment Policy Act (SEPA) requirements.
14. The landfill-gas-to-energy industry has evolved considerably over the past decade. The industry is considered mature with acceptable risk levels for project developments. Many projects have been financed based solely on the anticipated revenue to be generated during project operation. Tables 1-3 and 1-4 provide summaries of the current status of electricity generation and direct utilization of LFG.

TABLE 1-1
SUMMARY OF POWER GENERATION TECHNOLOGIES APPLICABLE TO LFG

Options	Technical Feasibility/Reliability	Commercial Status	Environmental	Financial
Boiler/Steam Turbine	Scaleable proven process demonstrated worldwide	Largest LFG plants in US and Canada; limited application in small size	Comparable with others; may need FGR or other NOX control, possible CO concern	High capital cost; moderate O&M, with several reference products for comparison
Combustion Turbines	Available in wide range of sizes; operating worldwide in stationary power generation; high reliability specialty units built for LFG	Well demonstrated in 1-8MW sizes but not larger; potential for 20-40MW units but not demonstrated	Moderate concern for NOX control; larger sizes may need low NOX burners, water injection, or other control	Lowest capital cost; moderate O&M cost; availability may be a concern
Gas –Fired Engine Generators	Available in wide range of sizes; operating worldwide in stationary power generation; high reliability specialty units built for LFG	Many units well demonstrated 0.5 to 3.0MW sizes but not larger; 7-10 MW units available but not demonstrated on LFG	NOX major concern but many units 0.8-2MW using lean burn technology to comply with limits	Moderate capital and O&M cost may be reduced in larger sizes
Fuel Cells	Not successfully demonstrated in any size using LFG fuel	________	________	________
Microturbines	Operating in small applications; far too small to be considered further for 27MW project	________	________	________
Pipeline Gas	Several units operating in small applications; larger units demonstrated with limited technical success	Many projects of various sizes; limited commercial success but not on a 27MW scale	Processes vary; most emit only CO_2; other contaminants removed in sludge waste	Wide range of capital and O&M cost; mostly higher than other alternatives but possible second product/revenue source (CO_2)

CO – Carbon Monoxide CO_2 – Carbon Dioxide   LFG – Landfill gas   NOX – Nitrogen Oxides   FGR – Flue gas recirculation   MW – Megawatt

TABLE 1-2
SUMMARY OF TECHNOLOGIES

Technology (12)	Available Size Range (KW)	Capital Cost (installed) ($/MW) (1), (2), (3), (4), (5)	Operating Costs ($/KWHr) (2), (3), (4)	Emissions (PPMV @ 12% O_2)				Commercial Status	Commercial Operation on Landfill gas
				NOX	SOX	CO	VOCS		
Combustion Turbines	1,000-235,000	400 - 800	0.015 - 0.025	5 – 25	Neg.	Neg.	Neg.	Commercial	Yes @ 1-8 MW limited > 8 MW units
Boiler/Steam Turbine	1,000-700,000	1,100 - 1500	0.01 - 0.02	20 – 150	Neg.	-	Neg.	Commercial	Yes – Up to 50 MW
Engine – Generator	400 - 10,000	450 - 800	0.015 – 0.025	100 – 400	Neg.	Neg.	Neg.	Commercial	Yes – Up to 3MW units
Microturbines	25 - 300	$800 - $1,200	0.0075-0.0125	9 - 25	Neg.	Neg.	Neg.	Achieved Limited Commercial Status in 2000	No
Fuel Cells	50 – 10,000 (9)	$4,000 - $8,000	0.02 – 0.035 (6)	< 5	NA	NA	NA	Achieved limited commercial status in last 3 years	No
Pipeline Quality Gas Conversion	100 - ? (7), (11) (MM BTU/hr)	750 – 1500 (7)	0.02 – 0.04 (8)	0	0	0	NA	Commercial on Petro/ Byproducts	Several projects, limited small scale commercial success

(1) Assumes Municipal Ownership

(2) All costs included (Admin, Engineering, Construction, etc.)

(3) Base Loaded plant @ 90% Plant Capacity factor

(4) No Aux Fuel

(5) No Interconnect Cost

(6) Include Gas clean-up

(7) KW equivalent @ 25 % thermal efficiency

(8) Assumes twice power production for boiler/steam

(9) Available in modular stacks so top end of size range in undefined

(10) Low range of Nox emission assumes Low-Nox burners , ammonia injection or Selective Catalytic Reduction used.

(11) Custom designed, scalable, thermo-chemical-mechanical process

(12) No large medium BTU gas market available

TABLE 1-3
ELECTRICITY GENERATION LANDFILL GAS-TO-ENERGY PROJECTS

Utilization Technology	Operating Projects		Projects Under Construction	
	Count	MW Capacity	Count	MW Capacity
Reciprocating Engine	156	470	43	137
Gas Turbine	27	163	-	-
Steam Turbine	10	143	-	-
Combined Cycle	2	31	1	16
Cogeneration	2	8	-	-
Fuel Cell	1	<1	1	<1
Microturbine	1	<1	-	-
Jet Engine			1	6
TOTALS	199	814	46	159

TABLE 1-4
DIRECT UTILIZATION LANDFILL GAS-TO-ENERGY PROJECTS

Utilization Technology	Operating Projects	Projects Under Construction
Direct Thermal	28	4
Medium Btu	7	2
High Btu (Pipeline Quality Gas)	12	9
Boiler	25	1
Leachate Evaporation	19	2
Greenhouse	4	-
Vehicle Fuel	1	-
Unknown	4	-
TOTALS	100	18

"2000 Update of U.S. Landfill Gas-To-Energy Projects"

Dina Kruger, Atmospheric Pollution Prevention Division, Office of Air and Radiation, U.S. Environmental Protection Agency; Shelley Cohen, Landfill Methane Outreach Program, U.S. Environmental Protection Agency, Washington, D.C.

PROJECT CONCEPT AND OVERVIEW OF TECHNOLOGIES

PROJECT SITE

The Cedar Hills Landfill is located near Maple Valley, Washington and currently serves as the primary disposal site for solid waste generated in King County outside the City of Seattle. The Landfill opened in 1964, is owned and operated by the County, and serves a population of approximately 1.1 million. The Landfill is expected to reach its ultimate capacity in 2012.

The Landfill currently collects approximately 14 million cubic feet of landfill gas per day. This gas contains approximately 7 million cubic feet of methane. Landfill gas (LFG) is produced by the anaerobic decomposition of organic wastes and contains methane, carbon dioxide, and trace concentrations of other compounds. To collect, control, and destroy LFG, the Landfill has an extensive active gas collection system which routes the gas to a system of five flares located on the north side of the Landfill. The gas is flared on a continuous basis.

Several high-voltage power transmission lines pass across or near the Landfill site. These lines could be potentially used to transmit power generated at the Landfill. The Bonneville Power Administration (BPA) owns two 500kV and three 230kV lines that cross the southern part of the Landfill site. Near the southeast corner of the Landfill, one of the 230kV lines turns northward along the east side of the Landfill, another continues to the east and the third turns south. The two 500kV lines continue eastward. The 230kV line that runs along the south and east sides of the Landfill is leased by BPA to Puget Sound Energy until 2018. There is also a natural gas pipeline adjacent to the site.

LANDFILL GAS-TO-ENERGY INDUSTRY STATUS

The management of municipal solid wastes became a regulated industry during the 1970's and 80's when the practice of open burning of garbage dumps became intolerable. Soon afterward operators of landfills realized that if gases generated by the decomposing refuse were not managed, serious and even lethal consequences could occur. Operators began collecting the landfill gas ("LFG") in the late 1970's and discovered a valuable energy resource. The first known energy recovery project was built in 1981 and by 1990 the number had grown to nearly 100. By the end of 2000 there were over 300 operating projects either generating electricity or providing gas to an energy market.

The promulgation of Federal New Source Performance Standards and Emission Guidelines in 1996 contributed to the capture and use of LFG at large landfills, but smaller sites also supported energy recovery projects. The USEPA Landfill

Methane Outreach Program (LMOP) was created to provide technical support to both public and private landfill owners to encourage mitigation of greenhouse gases though LFG recovery and utilization. The program maintains a database of projects in the US that provides a useful snapshot of the industry status and trends. Tables 1 and 2 provide a breakdown of electricity generating projects, and direct gas sales or utilization projects.

TABLE 2.1
ELECTRICITY GENERATION LANDFILL GAS-TO-ENERGY PROJECTS

Utilization Technology	Operating Projects		Projects Under Construction	
	Count	MW Capacity	Count	MW Capacity
Reciprocating Engine	156	470	43	137
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Steam Turbine	10	143	-	-
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The average LFG-to-energy project is between 2 and 3 MW in size, the largest is over 50 MW and nearly 200 projects are planned or under construction. The Industry has evolved through many lessons learned. Several major manufacturers provide specialized equipment, designed for use in LFG recovery projects. Moreover, the industry is no longer considered experimental or risky, and many projects have been financed on the merits of their prospective revenues alone. The Cedar Hills landfill generates enough LFG to produce the electricity for nearly 15,000 homes and in light of the current status of energy pricing in the western US, an LFG-to-energy project is worthy of consideration.

PROJECT CONCEPT

PROJECT CONFIGURATION

The LFG-to-energy project would include:

- Designing, permitting, and constructing a gas processing and/or power plant within the Landfill site. The power plant would include a tie-in to the existing gas collection system, a means of conditioning/cleaning the gas, an engine or steam boiler to burn the gas, electric generators, and a utility-grade electric switchyard.
- For Electricity generation options constructing an intertie to Puget Sound Energy distribution system and delivering all electricity to the PSE System.
- For Natural gas production (no electricity) either liquified natural gas will be trucked from the site or gas will be delivered to a gas pipeline in the vicinity of the landfill.
- Keeping the flares in-place to serve as a backup system when the power plant is off-line, when gas production exceeds power plant capacity, or when the power plant is operating at partial capacity. The power plant can be designed to minimize flaring of gas.
- Negotiating the most favorable sales agreement for electricity and/or pipeline quality gas.
- Operating and maintaining the power plant for 15 to 25 years.

PROJECT SIZING

A preliminary examination of LFG data at Cedar Hills indicates that potential power generation would rise from roughly 17 MW in 2000 to about 22 to 26 MW in 2012 (just before assumed closure of the Landfill), and then gradually fall. For the purpose of this evaluation a power plant of 22 MW is assumed. The County may want to consider plants of larger or smaller capacity based on considerations of equipment availability and possible use of supplemental fuel (natural gas). Actual sizing of the project should be based on a detailed assessment of current and projected gas generation rates, the cost of variously sized units and the value of base loaded capacity.

TECHNOLOGIES CONSIDERED

The following six generation technologies were reviewed in this report:

1. Microturbines
2. Combustion Turbines
3. Boiler/Steam Turbine (Rankine Cycle)
4. Fuel Cells
5. Gas-Fired Engine Generators
6. Clean Fuel Production

The remainder of this section provides an overview of each of these technologies related to the following:

1. General Description
2. Capital Costs
3. Operating Costs
4. Emissions
5. Commercial Status

The table on the following page provides a summary of this information.

Microturbine and fuel cells are not considered feasible at this time because they are not available in capacities appropriate for the project and because they have yet to be demonstrated commercial on landfill gas applications.

These options are briefly discussed for information purposes.

Clean fuel production has limited commercial operating history and we are not aware of any commercial operation of this technology on a comparable scale to the Cedar Hills project. Nevertheless, this technology is considered because it appears to offer some advantages provided that it can be demonstrated as commercially viable.

TABLE 2-3
SUMMARY OF TECHNOLOGIES

Technology (12)	Available Size Range (KW)	Capital Cost (installed) ($/MW) (1), (2), (3), (4), (5)	Operating Costs ($/KWHr) (2), (3), (4)	Emissions (PPMV @ 12% O_2)				Commercial Status	Commercial Operation on Landfill gas
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GENERATION TECHNOLOGIES

TURBO GENERATORS

GENERAL DESCRIPTION

Three types of Turbogeneration Prime Movers are reviewed in this report, microturbines, combustion turbines and the application of Rankine cycle base, boiler/steam turbine generation.

Microturbines

Microturbines are small versions of traditional gas turbines with similar operational characteristics. They are based on designs developed primarily for transportation-related applications, such as turbochargers and electric power generation in aircraft. In general, electric generators using microturbines as the prime mover are designed to be reliable with simple designs. Some have only one moving part, with the prime mover and generator on the same shaft; typical sizes are 20 to 300 kW, considerably smaller than would be practical for a system to handle the entire gas flow at Cedar Hills.

Microturbines have recently achieved commercial status based on the many demonstration and evaluation units in the field. Several companies, some of which are quite large, are committed to making these devices a viable, competitive generation option at larger sizes than currently available. One key characteristic of microturbines is that their simple design lends itself to mass production—should significant demand materialize. Until demand does materialize—so that manufacturing can scale-up economically—microturbines will remain a "near" commercial option that cannot compete on an economic basis.

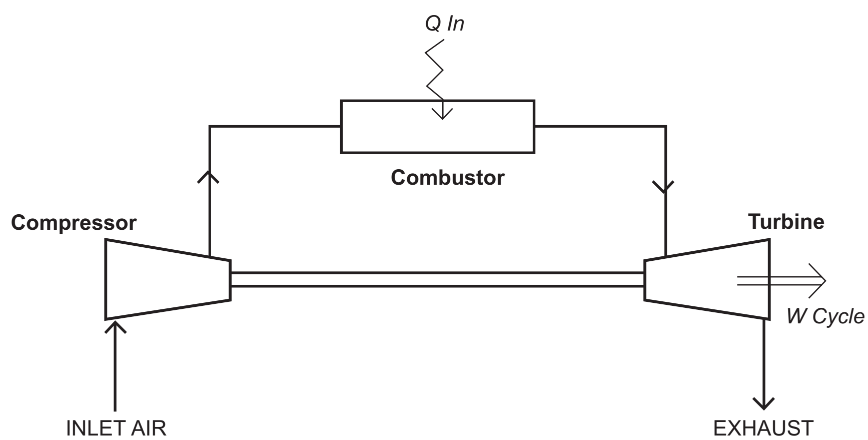
Due to this small size they are not suitable for use at Cedar Hills, and are not considered further in this review.

COMBUSTION TURBINES

OVERVIEW OF TECHNOLOGY

Stationary combustion turbine ("CT") technology used for power generation evolved out of advances in aviation and marine transportation during the late 1950's and 1960's. General Electric and Westinghouse corporations both developed aeroderivative, and industrial frame turbines for power generation primarily for peaking duty during periods power consumption for their utility customers. During the subsequent period, several manufacturers have also developed combustion turbines intended for stationary power generation. A combustion turbine is a simple heat engine which uses multiple stages of specially designed fans to compress and expand air as the working fluid to convert chemical energy into mechanical energy. Large amounts of air are compressed in the inlet section, a small portion of which is combined with a hydrocarbon fuel (fuel oils, kerosene, or natural gas) in a combustion chamber(s), adding energy which is then partially recovered as the gases expand in the expansion or turbine section(s) of the engine. As shown in Figure 2-1, the simplest CT systems incorporate 1) an air compressor, 2) fuel combustor, 3) the turbine or expansion section, and 4) the exhaust.

FIGURE 2-1 – COMBUSTION TURBINE SCHEMATIC



Many configurations of power generating CT's are manufactured depending on their size, intended use, type of fuel and operating speed. Many use a single shaft for both compressor and turbine sections which is then coupled to the driven end of the generator. Others use a dual or triple shaft configuration because the compressor section and high pressure turbine stages operate at a considerably higher speed than the low pressure turbine stages and generator drive shaft. Some CT's are coupled to their generators through a gear reduction unit.

In general, CT's produce electricity in a very reliable, cost effective, relatively efficient manner with emissions comparable, or lower than other power generation technologies. CT's typically have fuel use (i.e. heat rates, HHV) range from 8,000 to 13,000 Btu/kWh. They are available with power output ranging from hundreds of kilowatts to very large units rated at hundreds of megawatts. In context with the current escalation in energy prices, the market for combustion turbines has become extremely competitive. Because of their modular nature, low capital cost, ease of installation and siting capability, a significant majority of capacity currently being installed in the US is CT based. The manufacturers of some larger frame units are backlogged to the year 2004 and beyond.

CAPITAL COST

Recently the CT industry has experienced market competition unlike that in other energy production sectors. Capital costs have fallen as manufacturers have developed new materials and technologies capable of increasing the output, efficiency and reliability of their machines. Though not applicable to all sizes and uses of the technology, in general, the installed cost of new generation is between $400 and $800/MW. Systems in the range of 3 to 20 MW have not benefited from the level of market competition and technological advancement and tend toward the upper end of the range. Note this discussion is limited to CT's in a simple-cycle configuration, or without the capture and reuse of the energy rejected in the exhaust gases to the environment. Such systems (Combined Cycle) are gaining popularity in a base-loaded power production capacity, but are not well represented in the LFG-to-energy industry.

OPERATING COST

Due to the simplicity of the operating cycle and lack of ancillary processes and equipment, CT O&M costs tend to be lower than in other forms of power generation. Routing maintenance is typically limited to inspection and cleaning of critical elements. Many turbines have major maintenance intervals approaching 20,000 hours or more of continuous operation. The major maintenance and rebuild requirements are however, comparatively high. A major overhaul usually requires shipment of the entire unit, to the original manufacturer with costs approaching a significant portion of the original purchase cost. CT's also typically require a high inlet fuel pressure and have little tolerance for contaminant or particulate bearing fuels. Fuel preparation can be a major contributor to O&M costs. As with other power generation alternatives, O&M costs vary with final equipment selection, required ancillaries, fuel type and compression costs, but are generally between $0.015 and $0.025/KWh.

EFFICIENCY/RELIABILITY

Stationary combustion turbine technology has become the leading power generation equipment, selected for both peaking and base-loaded operation, in the US. There are numerous reasons for this, however the efficiency and reliability of CT's is a factor. Typical plant availability for CT units from the major manufacturers burning natural gas or oil is 90-95%. The use of non-standard fuels such as LFG may impact plant reliability and performance due to the necessity of additional fuel conditioning or treatment equipment. CT efficiency is dependent on numerous factors including ambient conditions, full or part loading, and type of equipment. Generally, however they are slightly more efficient than comparable forms of carbon fuel based power generation equipment including boiler steam turbine units and some engine-generators.

EMISSIONS PERFORMANCE

Many populous areas of the US are already at the limits of acceptable pollution standards for NOx, CO and ozone contamination. Within these areas, restrictions of pollutant emissions are strictly controlled and CT technology may offer the only acceptable means of providing additional generation capacity. Low-NOx burners, water and ammonia injection techniques are commonly used with larger

CT's to reduce emissions. This technology has also been shown applicable to a wide range CT sizes and fuels. Non-standard fuels pose a challenge, however testing on a wide variety of units has shown NOx and CO emissions can be maintained at acceptable levels. The project size or net electrical output also dictate the compliance measures required and smaller CT projects may need little or no emission controls.

COMMERCIAL STATUS

As previously mentioned, the commercial use of CT technology has grown significantly in the past decade and is now considered the leading power generation technology worldwide. Numerous manufacturers and vendors offer systems with capacities from approximately 1 MW to nearly 235 MW in a single unit. Although most require natural gas fuel, many types and sizes of CT's are multi-fuel and can accommodate medium and low Btu fuel inputs. One manufacturer offers several units specifically designed for use with non-standard, medium Btu, gaseous fuels and have over a decade of operating experience with them. Others offer similar capabilities in a small to medium (4-8 MW) range.

BOILER STEAM TURBINE

OVERVIEW OF TECHNOLOGY

The traditional means of fossil fuel based power generation in the past 75 years has involved the use of boiler and steam turbine technology. Typical boilers combust solid, liquid or gaseous carbon fuels in combination with air in an enclosed heat exchangers to create high pressure steam. Gaseous fuel boilers can use either water-tube or fire-tube configurations to generate and collect steam for distribution to the inlet of a steam turbine. The steam expands through the turbine stages similar to the expansion of hot gases through the high-pressure stages of a combustion turbine. The change in pressure is converted into angular momentum of the turbine shaft resulting in the spinning of an attached generator, thus producing electricity. The steam is never condensed within the turbine but must them be cooled and further reduced in pressure before returning to the boiler as feedwater. Significant thermal energy can be further extracted from the steam if there is a local demand such as district heating or low pressure process heating. Otherwise the steam is condensed mechanically via a cooling tower and returned to the boiler.

This thermodynamic process is known as the Rankine Cycle. Because of the large amount of equipment and processes involved, the Rankine Cycle is typically used in larger scale power production applications, above 5 to 10 MW. Also, the largest of fossil-fired power plants (700 to 3,000 MW) utilize the Rankine Cycle because it is scalable to almost any size. The process tends to be comparatively complex but allows large-scale power generation at the lowest O&M cost and greatest equipment service life. The Rankine Cycle is best suited to stable, long duration, base-loaded power generation in the upper size ranges. Typical fuel use (i.e., heat rates, HHV) range from 10,000 to 14,000 Btu/kWh.

Smaller Rankine cycle projects tend to have higher capital and O&M costs than other similarly sized alternatives such as combustion turbines and reciprocating engines. They also require a water source and proper water softening, conditioning and disposal systems. Emissions from Rankine cycle power production for a gaseous fuel tend to be comparable with other technologies but require frequent monitoring and adjustment to maintain proper combustion conditions within the boiler. Additionally, the use of LFG as fuel may require flue gas recirculation (FGR) or other systems to maintain emissions control and reduce the corrosive effects of the gas.

CAPITAL COST

Boiler and steam turbine facilities generally have an installed capital cost in the range of $1,100-$1,500/kW, depending on size, equipment selection, required emissions controls, and type of cooling systems employed. They require larger engineering and site development budgets than other projects because of their physical size and number of processes involved. Smaller package units can be erected in a modular arrangement while larger field-erected units require more specialized construction techniques. Because Rankine cycle power generating systems rely on several interconnected processes and ancillary systems, with large ranges of cost within each system, cost uncertainties usually remain until final equipment selection is made.

OPERATING COST

Although Rankine cycle projects (particularly gaseous fuel projects) generally have low labor requirements and infrequent major maintenance, the individual processes involved require constant monitoring and frequent adjustment. Sinking funds necessary for major maintenance are comparatively large, e.g. steam turbine overhaul or boiler re-tubing. O&M cost are probably more dependant on project size than any other power generation technology, but generally range between $0.01 and $0.02/kWHr. Large (>100MW) facilities can have O&M costs lower than $0.01/kWHr while small plants, because of the economies of scale, exhibit O&M costs significantly higher.

EFFICIENCY/RELIABILITY

Another reason Rankine cycle projects tend to the larger scale of power generation facilities is their proven reliability and competitive efficiency. They are ideally suited for base-loaded applications and can run for years without major maintenance or frequent shutdowns. Because of the numerous processes, thermal efficiency is slightly less than modern engines and combustion turbines, however their reliability and stable operation must be factored into the selection criteria.

EMISSIONS PERFORMANCE

Emissions from gaseous-fueled boilers vary widely with the type of fuel used, type of burners, combustion management systems and emission controls. Generally, LFG fueled boilers require minimal emission control measures other than flue gas recirculation ("FGR") and burner management. The project location and areas attainment status are typically the most significant factors. NOx emissions can be controlled with FGR, sulfurous oxide emissions are low due to the typically low sulfur content in LFG. Carbon monoxide and unburned hydrocarbon emission are low due to the high turbulence and mixing of the fuel gas within the boilers combustion zone.

COMMERCIAL STATUS

The Rankine Cycle is arguably the most established, commercial power generation technology in existence. There is no question as to the technologies potential applicability from the standpoint of proven performance. The primary limitation regarding LFG to energy is the relatively small size (1-8mW) of nearly all LFG recovery projects. Those few large projects (Puente Hills – 50 MW, Coyote Canyon – 20 MW, Gazmont - 23 MW and others) in the US and Canada, typically employ a boiler-steam turbine technology.

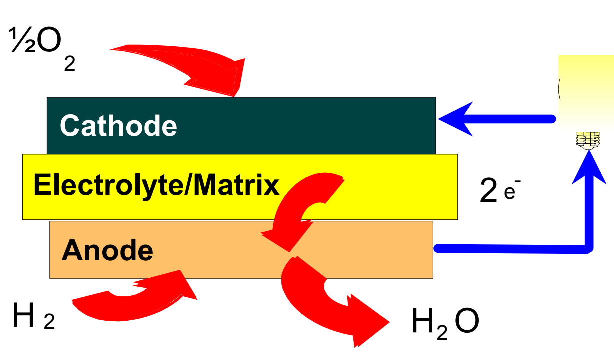
FUEL CELLS

OVERVIEW OF TECHNOLOGY

Fuel cells are electrochemical devices that convert the chemical energy of the reaction of hydrogen and oxygen in the presence of an electrolyte into electric current. The conversion process is very efficient – in many cases much more efficient than combustion technologies - with minimal environmental impact.

The essential chemical reaction, which is similar to a battery, is shown below:

FIGURE 2-1 – FUEL CELL SCHEMATIC



Hydrogen and oxygen are passed over the anode and cathode and then interact with an electrolyte producing heated water and electric current. The type of electrolyte involved differentiates fuel cell technologies. The electrolyte chosen determines the complexity of the unit, the amount of heat and electricity produced, and the need for other gaseous components in the fuel (or the degree of purity in the fuel supply).

Commercial prototypes of all fuel cell types have been demonstrated, or are currently in operation. However, their use in landfill gas applications is very limited and is not suitable for use in a facility as large as the Cedar Hills project.

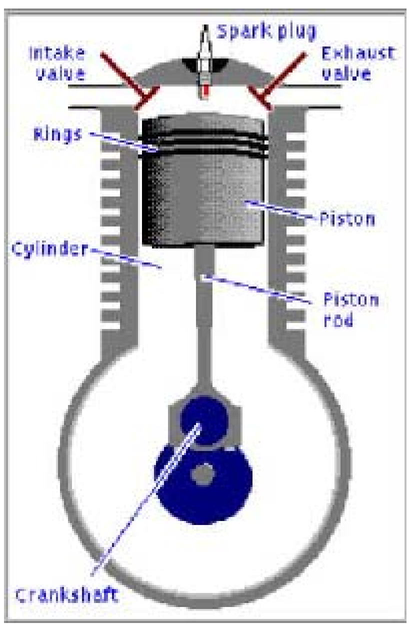
GAS FUELED/SPARK IGNITED INTERNAL COMBUSTION ENGINE GENERATORS

OVERVIEW OF TECHNOLOGY

A reciprocating (piston-driven), gas fueled internal combustion engine generator set (genset) includes the engine as prime mover, coupled with an electric generator to generate electricity. The engine provides mechanical power/torque used directly, or to turn an electric generator to produce electric power.

In this case, the engine employs the Otto heat cycle characterized by "spark-ignition" of fuel, by a spark plug, in a chamber that contains a piston. The piston is connected to a crankshaft. As the piston moves up and down during operation, the piston rod converts the reciprocating motion of the piston into the rotating motion of the crankshaft (see **Figure 2-2**).

FIGURE 2-2 – FOUR-CYCLE ENGINE



Internal combustion engines usually use a four-stroke cycle similar to automotive and other transportation engines.

In theory spark/gas engines can provide service to almost all applications requiring electric power or mechanical work. Depending to some extent on design, spark/gas engines can start and stop quickly and can respond to load changes rapidly. This makes them particularly suitable for peak load/load-following applications. For many industrial and/or institutional applications, gas/spark engines provide reliable baseload or intermediate duty cycle service. They are also well suited to combined heat and power (cogeneration) applications requiring relatively low temperature output.

Relative to combustion turbine-based plants, spark/gas engines are especially competitive for power plants whose maximum electrical output is about 5 MW or less.

CAPITAL COST

Spark/gas systems have an installed capital equipment cost that typically range from about $450 - $600/kW, depending on size, intended duty cycle, equipment options, air emission(s) requirements, number of units ordered, and special engineering required. Some vendors expect prices below $400/kW by about 2002.

Prices have declined steadily as more units are sold for generation and as competition has increased from other conversion devices such as microturbines. Competition has also increased between vendors and system integrators. Significant research and development in the transportation sector also drives price declines for engines.

OPERATING COST

Spark/gas engines tend to have maintenance costs that are somewhat higher than alternatives, primarily due to the higher number of moving parts. However, new materials, engine designs, “predictive” diagnostics, and operation and maintenance protocols are all tending to drive maintenance costs down. Maintenance cost can range from about $0.01/kWh to over $0.05/kWh, depending mostly on engine design, number of engine start-ups, the amount of power output “cycling” during operation, and whether a sinking fund is maintained for periodic engine overhauls.

Service life should be at least 20 to 25 years if properly maintained. Maintenance cost typically ranges from 0.02 to 0.05$/kWh. Frequent cycling increases maintenance costs considerably.

EFFICIENCY/RELIABILITY

Existing spark/natural gas-fueled reciprocating engine gensets are made using well-proven technology and are quite reliable. Research and development for transportation-related applications helps to continue the steady, evolutionary technological improvement. Spark/gas engines can be cycled frequently to provide peaking power/load-following, or they can be used for intermediate or baseload duty cycles, or for combined heat and power (cogeneration) applications. Typical fuel use (i.e., heat rates, HHV) range from 9,000 to 13,500 Btu/kWh.

EMISSIONS PERFORMANCE

Spark/gas engine NOx emissions may pose a hurdle for engine use in areas that are “non-attainment” areas under provisions of federal law, specifically, areas where ozone is a problem. Furthermore, though modern spark/gas engines’ NOx emissions are much lower than emissions from predecessors and are lower than its key competitor, diesel engines, spark/gas engines’ NOx emissions are still somewhat higher than those from modern combustion turbines and certainly higher than NOx emissions from fuel cells. For the most part, the same applies to carbon monoxide (CO) and unburned hydrocarbon emissions.

It is important to note that emission control schemes/technologies for spark/gas engines are improving continuously, leading to better and/or lower cost alternatives, including novel combustion concepts and improved catalysts for use in the selective catalytic reduction process. (Catalysts *accelerate* chemical reactions but are not consumed in that reaction. They neutralize offending chemicals by a) attracting the chemicals to their surface such that b) chemical bonds in the offending chemicals are weakened, making beneficial chemical reactions easier.)

Catalytic converters, used and developed mainly for automobile exhaust systems, convert three key pollutants (nitrogen oxides, carbon monoxide, and hydrocarbons) produced by combustion of fuel spark/gas engines to less harmful chemicals or even constituents (ideally nitrogen, carbon dioxide, and water).

COMMERCIAL STATUS

Many gas/spark engine generation systems are in service worldwide, providing either mechanical work or electricity. Systems can be purchased from, and serviced by, a global network of vendors and dealers.

Spark/gas engines are available in a range of unit sizes—making them very modular (i.e., total plant output is not limited to maximum unit size). System electric power output ranging from several kilowatts to 5 MW is possible, with outputs between 50 kW and 2 MW being most common.

Several manufacturers produce “turbocharged, lean-burn” engines with outputs between 400-2,100 KW which are specifically designed or modified for medium-Btu gas applications. They are produced with primarily two types of inlet carburation systems, and each has over a decade of operating experience specifically on LFG

CLEAN FUEL PRODUCTION

OVERVIEW OF TECHNOLOGY

An alternative to power production at the point of gas geneation is the production of a fuel grade gas through the use of various processes as described below.

AEROSOL AND PARTICULATE REMOVAL–FILTRATION

Some of the smaller liquid droplets that can result from dispersion (or even a “fog” as condensation occurs in the cooling gas), and smaller particulates, may not be removed by demisters. Filtration is used to remove such moisture and particles.

Filtration is relatively straightforward; both wet and dry filters are used. Although the absolute cutoff for particle size is, apparently, a matter of personal choice for the equipment selected, the range is generally between 0.3 and 3 microns. Actual filter size selection depends on the gas quality requirements.

One type of filter widely used is the coalescing filter; it will remove both entrained liquids and solids. Liquids intercepted by the filter medium coalesce, drain from the filter, and are managed with the rest of the condensate. For dry gas, absolute cutoff filters are often utilized. These are generally canister filters with replaceable elements, although a wide variety of filtration devices are used.

COOLING AND REFRIGERATION

As LFG is delivered through a blower, or compressor, its temperature is elevated as it is compressed. At any subsequent point, as its temperature or pressure drops , condensate tends to form. Many approaches are used to minimize the impact of condensate formation. Some operators elect to cool the gas by simple air-cooled, or water-cooled, heat exchangers to a design dew point and then to preheat the gas just before it is introduced, since the gas is easier to ignite when warm.

When refrigerated, the gas stream is usually cooled to between 34 and 40°F (the lower temperature limit is set by the requirements of the downstream equipment or the icing that occurs on heat exchange surfaces). This condenses out most of the moisture, and a fraction of other condensable compounds, depending on their vapor pressures and other factors.

NMOC REMOVAL

Some contaminants not removed by refrigeration include lower boiling point Chlorinated Hydrocarbons and Halogens, which form potentially damaging acid gas compounds. Several cleanup methods may be used to remove these contaminants. One method applies a solvent to remove these Non-Methane

Organic Compounds ("NMOC"s); the solvent can also be chilled to increase removal efficiency. Activated carbon beds can also be used to remove halogens and other organics.

HI-BTU, OR PIPELINE QUALITY GAS PRODUCTION

In lieu of a power generation opportunity or other means to use LFG, numerous projects have been constructed to remove carbon dioxide from the gas for beneficial use of the remaining methane. Several projects have also attempted to recover the CO2 for reuse as a secondary revenue-producing product. These processes not only provide the contaminant removal functions described above, but also produce a marketable pipeline quality or Hi-Btu gas similar to natural gas. Most of the technologies involved in the production of Hi-Btu gas involve a vapor-swing absorption process involving high gas pressures and low temperatures. Others use membrane and reverse osmosis systems to separate the methane and carbon dioxide into constituent parts. These processes are generally patented and of a proprietary nature and are marketed and sold exclusively by private firms.

Demonstration projects funded in part by Federal and State agencies have proven the technical feasibility of a number of Hi-Btu projects. Others are private venture arrangements between landfill owners and the process developers. According to the USEPA Landfill Methane Outreach Program there are currently twelve operating Hi-Btu projects in the US, and several are currently in the planning or implementation process. It is not known how many of these are commercially successful, beyond the demonstration phase. The potential market for these projects include vehicle fuel (ideal for diesel equipment use at operating landfills), direct natural gas pipeline sales, and high purity fuel for energy production in fuel cells, microturbines, etc.

CAPITAL COST

Hi-Btu project process equipment generally includes compressors, chillers, heat exchangers and pressure vessels and associated piping, electrical equipment and controls. The purified gas pressurized and stored for distribution, or routed to a natural gas pipeline. Often an interconnecting pipeline must be installed, which can constitute a significant portion of the project capital cost. The variables involved include the type of process equipment and the length of pipeline necessary to reach the end user or interconnecting natural gas pipeline. Because the processes are proprietary and not well established, it is extremely difficult to estimate a Hi-Btu project capital cost. Assuming the interconnecting pipeline or gas compression and storage costs are minimal, assumptions can be made based on similar process equipment used in the petrochemical industry. For comparison purposes, the volumetric production of Hi-Btu gas is converted to KW based on a 25% thermal efficiency. From this, it is estimated that the capital cost of a pipeline or Hi-Btu process can be between $750 and $1500/KW.

OPERATING COST

In comparison with electric power generation, pipeline quality gas production generally requires greater gas compression, thermal treatment and consumables expenditures. Like capital costs, O&M costs are also difficult to estimate in a generic sense. However, assuming parasitic power and consumables costs are roughly twice those of a comparable power generation project, the range of O&M cost could be between $0.02 and $0.04/KWHr.

EMISSIONS PERFORMANCE

Unless the CO2 separated from LFG in a Hi-Btu process is recovered as a saleable byproduct, it is generally vented to the atmosphere. The remaining contaminants, depending on the process used, either is removed in the form of a liquid sludge, or burned as a concentrated sidestream of methane and organic hydrocarbons. This poses another emissions source or need for disposal of the contaminated sludge. Generally however, if properly treated, a Hi-Btu production process is generally considered low in emissions to the atmosphere.

COMMERCIAL STATUS

New and potentially promising treatment processes are developed routinely and numerous pipeline and Hi-Btu projects have been permitted and constructed. Their commercial success is however, not well documented and to our knowledge, a facility comparable in size to one conceivable at the Cedar Hills landfill has not been demonstrated. If the County were interested in pursuing this technology, a demonstration of commercial viability would be required. Note that several European projects converting digester and landfill gas to commercial vehicle fuel have existed for over a decade. These projects, though desirable and technically successful, are heavily subsidized by various government programs and are not considered a demonstration of commercial success.

New technologies are currently being evaluated by at least two vendors in the US. Because of the potential to recover saleable CO2 and minimize point source emissions at the Cedar Hills Landfill, these technologies could, if well demonstrated in the future, be considered.

DCS, SCADA AND SUPERVISORY CONTROL

Modern power generation and process control systems consist of sophisticated networks of monitoring, control, protection and communications equipment. Regardless of the LFG energy recovery technology utilized for a project at the Cedar Hills Landfill, a system capable of monitoring and controlling critical functions from a central control location will be utilized. A DCS, or Distributed

Control System is a computer based means of collection process information from instrumentation and control devices located throughout the power plant. The DCS also allows for either automated or manual adjustment of process conditions such that during normal operations, no human intervention is required. All DCS's contain programming which automatically corrects for variations in process conditions (speed, pressure, temperature, level, positions, etc) to maintain a stable, desired operating status. Various alarm or emergency action conditions are automatically carried out by a DCS, in the event of a system upset or component failure.

For example, engine-generators are typically equipped by their manufacturer with individual engine management control computers to maintain fuel status, lubrication, speed and generator synchronization for each unit. If a power generation facility contained several engine-generator sets, the DCS would monitor each of the engine management controllers as well as all plant ancillary systems such as fuel preparation, cooling systems, electrical systems, emissions controls, etc.

It is not anticipated that a LFG recovery and energy production system at the Cedar Hills Landfill would be operated autonomously or remotely. An operations and maintenance staff would likely be required, not only to insure plant availability and to react to unexpected conditions, but also to monitor and make adjustments for the highly variable nature of LFG production.

SCADA or Supervisory Control and Data Acquisition, is a communications and control network typically associated with remote operation and monitoring of utility power generation systems. Application of SCADA systems allow the unattended operation and networking of numerous distributed generators and electrical control equipment from a central facility. If a power generation system were implemented at the Cedar Hills Landfill, it is anticipated that a SCADA system would be installed in conjunction with the plant DCS to assist utility grid managers in the Puget Sound area with load planning, management, communication and control.

The cost for such DCS and SCADA systems are included in the range of unit costs provided here-in.

INTRODUCTION

Most energy generation equipment used in the LFG to energy industry is designed to operate on a constant and reliable supply of clean, relatively dry pipeline gas fuel. Pipeline gas, which is primarily methane, is delivered directly at a constant selected pressure and at a relatively constant temperature; it is a reliable and predictable fuel source.

Landfill gas (LFG), however, cannot be characterized as possessing the desirable and predictable characteristics of pipeline gas. It is a wet and dirty gas; it is not always deliverable at a constant quality, or consistent quantity; and its composition is in the range of 40 to 55 percent methane, 35 to 45 percent carbon dioxide, with some nitrogen and trace gases, and perhaps oxygen. If it is to be delivered to the energy conversion equipment at a reasonably constant temperature and pressure it must be processed using a compressor, or blower, to achieve the desired pressure. Its temperature moisture and contaminant levels must be managed by appropriate means, as required by the particular power generation application.

Some manufacturers of energy conversion equipment have modified their equipment to accept non-pipeline-quality gas, or worked with the operators of such projects to develop suitable conversion projects. However, there are numerous cases of unsuccessful projects, both from an operator's and a manufacturer's view, which serve to document the difficulties encountered in the use of LFG as a fuel source.

The intent of this paper is to raise many of the issues associated with the use of LFG as a fuel for energy conversion equipment and provide some insight regarding what has been done in the LFG-to-Energy business sector to develop successful projects.

ISSUES WITH LFG USE AS THE FUEL FOR ENERGY CONVERSION EQUIPMENT

COMPARISON OF LFG AND PIPELINE GAS

Since LFG is so different from natural gas it is important to focus on the dissimilarities and their consequences to energy conversion use. Table 3.1

presents a comparison of some of the composition and component variations between the two gases

TABLE 3.1
COMPARISON OF COMPONENT CONCENTRATION AND OTHER PROPERTIES: PIPELINE QUALITY GAS VS. LFG

Component	Pipeline Gas	Landfill Gas
Methane (CH_4), %	90-99	40-55
Ethane + propane, %	1-5	0
Water vapor, %	<0.01	1-10
Carbon dioxide, %	0-5	35-50
Nitrogen, other inerts, %	0-2	0-20
Condensable hydrocarbons (NMOCs) ppmv as haxanne	0	250-3,000
Chlorine in organic compounds, micrograms per liter	0	30-300
Hydrogen sulfide, ppm	0-15	5-50
Higher heating value, Btu/ft^3	950-1,050	360-490

The concentration of noncombustible gases in LFG dilutes the energy content, relative to pipeline gas, reducing its energy content per unit volume. LFG combusts at a lower temperature than pipeline gas and has a slower flame-front propagation.

ENERGY CONTENT AND ITS VARIABILITY

Because LFG has only about 50 percent Methane it has about 50 percent of energy of pipeline gas. About 50 percent more LFG fuel is, therefore, needed to develop the same power obtained from equipment using natural gas. Fuel metering equipment must, therefore, introduce about twice the fuel gas normally provided when using conventional gas fuel.

The variation in LFG supply (both quantity and composition) was previously discussed. Since the equipment that meters gas-based fuel-to-energy equipment is normally designed for a constant-heating-value fuel, variations in heating value can create problems, sometime serious ones. While a boiler project may not be seriously affected by a changing heating value, a lean-burn reciprocating internal combustion (IC) engine is especially sensitive to variations in the energy content of the gas fuel.

LFG COMBUSTION CHARACTERISTICS

Flame-front propagation with the lower-Btu LFG-air mix is slower than with the pipeline gas-air mix, largely due to the presence of CO_2. For proper combustion to occur with burners, the flame front must propagate faster than the gas flows away from the burner. Under circumstances that occur with some burners, for example, conventional space heaters, the flame may lift from a burner orifice, or with a very low CH_4 level, go out, if the flame front propagates too slowly.

CONTAMINANTS AND CORROSION

LFG typically contains contaminants that can significantly increase required maintenance of combustion and processing equipment and even cause catastrophic equipment failures if not properly monitored or treated. Organic hydrocarbons, halogens, chlorinated compounds and oxides of silicon (siloxanes) all must be periodically monitored to insure their concentrations are within the acceptable limits of selected equipment. Lubricant testing is the most common means of contaminant identification, but visual inspection and frequent maintenance procedures must be in place to insure the success of an energy recovery facility.

Acid gases can form in the exhaust of several types of combustion and heat recovery systems causing harmful corrosion and depositions. Internal combustion engines are particularly susceptible to valve damage and excessive piston and bearing wear due to these contaminants. Compressors, heat exchangers and filtration systems must also be frequently inspected. Specific operating procedures, such as maintaining exhaust temperatures above the condensation point of corrosives, or increasing the frequency of certain component replacements, have evolved to minimize these problems, but contaminant mitigation remains among the prime concerns within the LFG to energy industry.

LFG EXTRACTION FROM LANDFILL WELL FIELD

EXTRACTION SYSTEM

LFG is usually extracted at a vacuum of 20 to 70 inches of water column with a capacity of 4 to 10 inches available at the furthest well. Vacuum is provided by a blower for low delivery pressure, or a compressor for higher delivery pressure. The compressor may be combined with a blower in certain applications.

The extraction system must be managed and operated so that it has a minimum impact on the LFG fuel delivered to the energy conversion unit. Occasionally, the extraction system is managed by a different party than the party managing the energy conversion system. Scheduled down time by either party must be coordinated so that it has minimal impact on the energy conversion system. The extraction system manager needs to have a well financed and managed O&M program to minimize extraction system impacts on the energy system project's performance. Sudden downtime may significantly affect the energy conversion equipment and its performance.

CONDENSATE MANAGEMENT

Liquid removal is practiced to some level in all LFG energy conversion projects. It starts in the gas extraction system pipe network with the incorporation of condensate management collection stations. A liquid knockout, or liquid surge tank, is usually incorporated before LFG entry into the blower, or compressor, unit. These condensate interceptor tanks should be large enough to handle the maximum amount of liquid anticipated; tanks of 1,000 to 5,000 gallons are not uncommon. Regardless of design, gas velocity slows in the tank because of the large cross section, and condensate de-entrains and falls to the bottom of the tank. Tanks may be baffled. Frequently, the upper area of the tank will contain packing, mesh, or "demister" filters that remove particulate matter and smaller droplets from the LFG. The liquid collected by the mesh or packing also drops to the bottom of the tank. Particulate materials may not be removed where only a blower is used, however common practice includes particulate filtration when energy recovery is involved.

Condensate can be generated wherever gas cools within the gas extraction, pretreatment, and energy conversion systems. Condensate within the pretreatment plant may be generated at various locations; some will be generated even without gas processing, because the collection system or ambient-temperature is almost always below the internal landfill temperature (typically 90-130^{o}F). Both compression with aftercooling and refrigeration can generate large amounts of condensate as the gas loses its capacity to hold water and other condensables. Condensate may be removed by appropriately located drain legs leading to an appropriate collection/storage/removal unit.

Condensate management may be simple, or difficult, depending on site-specific circumstances. Disposal can present a high expense if the condensate must be treated on site and then hauled to a licensed disposal facility; if it can be discharged to a nearby sewer system or returned to the landfill, costs will be lower.

Cedar Hills has installed condensate management systems including: Cyclone Separation, Knock-outs, Main Gas Line Drains.

EVALUATION OF OPTIONS

INTRODUCTION

This section provides a comparison of the options described in Section 2 with critical implementation criteria. The purpose of this analysis is to identify which technologies appear promising for development at Cedar Hills. The options considered promising are then analyzed relative to life cycles cost in Section 5.

The critical implementation factors included in this analysis are:

Technical Feasibility/Reliability: Is the technology appropriate and is it reliable for use on landfill gas

Commercial Status: Is the technology proven and capable of being financed

Environmental Factors: The level of emissions produced

Table 4-1 that begins on page 4-3 identifies the pros and cons of each option to these factors.

OTHER FACTORS AFFECTING PROJECT FEASIBILITY

Development of landfill gas-to-energy project at Cedar Hills is relatively complex and if the County proceeds it will require a significant capital investment. As with any project of this magnitude, a number of factors will affect the success of the project. This report provides an overview of technologies and identifies some potentially promising technologies. There are a number of critical issues that are outside the scope of this evaluation and need to be addressed before proceeding. These issues are discussed briefly below.

ENERGY PRICING

The value of energy produced by the project will have a major impact on project economics. Unfortunately forecasting market price for electricity for the mid to long term is difficult. There are two liquid trading points for electricity in the Pacific Northwest region. One is at Mid-Columbia, which is in Washington State, and the other is at the California-Oregon border (COB). Given their proximity and the liquidity of the market, the Mid-Columbia and COB prices are closely correlated. Average electricity prices during high load hours in the Pacific Northwest mid-Columbia market increased by $140 per megawatt-hour between June 1999 and June 2000, and light load hour prices increased by $46/MWh. The comparable price increases in Southern California were \$113/MWh and \$28/MWh.

The increase in natural gas prices does partially explain the observed increase in electricity prices. Between the summer of 1998 and the summer of 2000, natural gas prices as Sumas (on the Washington-British Columbia border) increased over the same period from about \$2.40 to \$4.18 per million BTU. Prices have moved substantially higher during late August and September. During mid-September, prices at Sumas were \$4.60/MMBtu and prices into Southern California were over \$6.00/MMBtu, although the California prices were affected by a serious pipeline explosion. Higher natural gas prices, should they persist, will result in higher "average" prices of electricity. Depending on the generating technology used, a \$2/million BTU increase in natural gas prices (roughly consistent with the doubling of gas prices seen by mid-summer) could increase overall electricity prices by between \$15 per megawatt-hour and \$22 per megawatt-hour.

The long-term equilibrium prices in a competitive, liquid market should be driven (capped) by the total cost of new entry. Considering the capital and operating costs of new projects brought online , the long-term market price for electricity in the Pacific Northwest market should be in the range of \$40-\$50/MWh (\$ 2001).

ENERGY SALES

The County has a number of options with respect to sale of energy produced by the project. Options include specific customers, contract duration and contracted energy price. These are issues which should be addressed if the County should proceed with the project.

OWNERSHIP

Several large public Solid Waste Utilities own and operate landfill gas-to-energy systems. Alternatively it is very common to have the private sector develop, own and operate these types of facilities.

PERMITTING/SITE USE

The Cedar Hills Landfill operates under various permitting constraints and has undergone numerous environmental reviews. Development of a LFG-to-energy project should be reviewed in the context of these requirements.

TABLE 4-1

Option	Technical Feasibility / Reliability		Commercial Status		Environmental	
	Pros	**Cons**	**Pros**	**Cons**	**Pros**	**Cons**
Microturbines		Too small on unit basis	-Demonstration funding my be available	- Not proven on LFG fuel		
Combustion Turbines	- Efficiency - Hi-Reliability – Low routine Maintenance – Simple Design	- Availability of suitable sized equipment – High compression required	- Proven in small to moderate sizes w/LFG	- Availability of suitable sized CT's - Limited LFG experience in large units	- Small footprint – Proven No_x control	- May require noise abatement
Boiler Steam Turbines	- Proven large LFG plants – High Reliability – Scaleable to any size – Handles LFG variability	- Corrosion Potential – Moderate Routine Maintenance	- Proven	- Not as flexible as systems w/multiple units	- Single air monitoring point/discharge	- Large footprint – No_x – CO controls may be required – Wastewater efficiency
Gas-fired Engine Generators	- Efficiency – Good reliability Many vendors and support	- High routine maintenance – susceptible to LFG variability	- Proven – Majority of LFG plants Multiple unit flexibility	- Limited experience in larger units	- Specialized LFG units available	- May require noise abatement – No_x control may be required
Fuel Cells	- Simple design – Low maintenance – High reliability	- Gas clean-up – No large units	- Demonstration funding may be available	- Not commercial on LFG fuel	- Cleanest Technology available	- Emissions from gas clean-up
Pipeline Gas	- Many Technologies – Simple membrane systems available	- Not proven reliability	- Possible CO_2 sales – Many possible gas users – Simplifies energy sales	- Not proven large scale – Not proven commercial	- Potentially cleanest technology – Eliminate point source emissions	- Hydrocarbon disposal

FINANCIAL ASSESSMENT

INTRODUCTION

Based on the preliminary review of technologies summarized in Sections 2 and 4, three are considered promising for use at Cedar Hills. These are:

1. Combustion Turbine
2. Boiler Steam Turbine
3. Gas-fired Engine Generators

These three are the only technologies that have commercial status on large landfill gas projects.

Production of clean fuel was identified as potentially promising technology, however it has not achieved commercial operation at a scale sufficient to provide capital and operating costs and performance data.

This section provides a summary of a preliminary life cycle cost estimate of the three combustion options identified above. It is intended to "bracket" project economics to help make a go/no go decision on proceeding to the next step of the process.

At this planning level cost analysis, we have not attempted to make refined cost comparison of the three technologies. Instead, we have identified a base case and several sensitivity cases for analysis:

Base Case: Considered most likely combination of capital O&M, and energy pricing over a 15 year evaluation period.

High Electricity Market Value: Assumes that the current run up in energy pricing lasts longer than expected and results in an average price of energy of 6.5 cents/kW over a 15 year period.

High Capital/O&M cost: Assumes base case conditions with capital and O&M at the high range.

Extended Operating Period (20 yrs): Assume base case over a 20 year period.

The following table provides a summary of the assumptions used in the analysis.

Electricity Generation				
Assumption	**Base Case**	**High Electricity Market Value**	**High Capital/ O & M Cost**	**Extended Operating Period (20 yrs)**
• Capacity of LFG facility, MW	22	22	22	22
• Annual availability of LFG-to-energy system, percent	90%	90%	90%	90%
• Wheeling cost, cents/kWh	0.30	0.30	0.30	0.30
• Capital cost of LFG to energy system	$20 million	$20 million	$24 million	$20 million
• Capital cost of utility system intertie	$750,000	$750,000	$750,000	$750,000
• Operating period, years	15	15	15	20
• Amortization of LFG system and intertie capital cost	15 years at 7.0%	15 years at 7.0%	15 years at 7.0%	20 years at 7.0%
• LFG-to-energy plant O&M. Cost, cents/kWh	1.8	1.5	1.8	1.5
• Value of offset power purchases, cents/kWh	4.5	6.5	4.5	4.5
• Rate of inflation	3.0%	3.0%	3.0%	3.0%
• Discount rate for computing net present value	7.0%	7.0%	7.0%	7.0%

Assume Common to All Alternatives

- Assume project becomes operational January 2002
- Evaluate annual average production only, not hourly generation and resulting hour-by-hour offset of power purchases, including peak period impacts
- Assume there is sufficient LFG to produce 22 MW consistently
- Assume no tax credits or other tax impacts. New or renewed tax credits for LFG-to-energy systems would likely improve the economics of this project.
- Assume use of existing LFG collection system, and that operations and maintenance costs are the same whether flaring or generating electricity.
- Assume no credit for offset in flare O&M costs.

LIFE CYCLE COSTS
The results of the Life Cycle Cost Analysis in 2001 dollars is shown below:

Sensitivity to Energy Market Pricing

Scenario	Life Cycle Cost Project Revenues (Costs)
Base Case	$31,300,000
High Electricity Market Value	$69,900,000
High Capital/O&M cost	$21,500,000
Extended Operating Period (20 yrs)	$43,000,000

Overall project economics are very sensitive to the value of electric energy produced. In order to provide an approximate estimate of the magnitude of that sensitivity the base case was analyzed using a range of energy values of from 4 to 12 cents per KWh. The annual projected project net revenue for the year 2002 was plotted relative to energy prices as shown below. In this analysis net revenue is the total electricity sales revenue less the total (capital and O&M) cost.

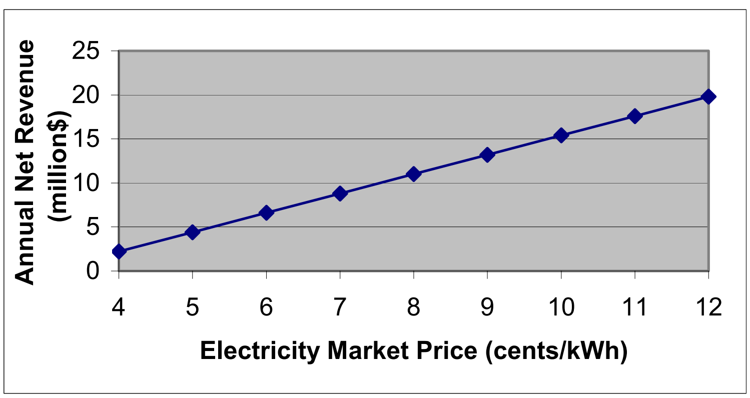


Table A-1

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
BASE CASE

This spreadsheet evaluates the preliminary Base Case feasibility of generating electricity from landfill gas at the Cedar Hills Landfill.

Assumptions

Capacity of LFG facility, MWe		22	
Annual availability of LFG system, percent		90%	(= plant capacity factor)
Wheeling cost, cents/kWh		0.30	
Capital cost of LFG to energy system, thousands 1999$		20,000	
Unit cost of system, $million/MW capacity:	0.90		
Capital cost of utility system intertie, thousands 1999$		750	
Operating period, years		15	
Amortization of LFG system and intertie capital cost			
Years		15	
Interest rate		7.0%	
LFG-to-energy plant ops & maint cost, cents/kWh		1.50	
Value of offset power purchases, cents/kWh		4.50	
Rate of inflation			
For operations & maint costs, wheeling costs		3.0%	
For value of offset power purchases		3.0%	
Discount rate for computing net present value		7.0%	

Assume project becomes operational January 2002
Evaluate annual average production only, not hour-by-hour generation and resulting hour-by-hour offset of power purchases, including peak period impacts.
Assume there is sufficient LFG to produce 22 MWe consistently.
Assume no tax credits or other tax impacts.
Assume use of existing LFG collection system, and that operations and maintenance costs of that system are the same whether flaring the LFG or operating the LFG-to-energy plant.
Assume no credit for offset in flare O&M costs.

Net present value (cost) with the above assumptions, $000: *$31,300*
(see calculations on next page to see how this was derived)

Table A-2

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
Base Case

Calculations

Year		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total capital cost $000	20,750												
Project phase		Design/permit	Const.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.
Operating year				1	2	3	4	5	6	7	8	9	10
Capital cost amortization ($000)													
Amortization period			Interest only	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I
Amount			1,453	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278
Power generated, 000 MWh	-	-	-	173	173	173	173	173	173	173	173	173	173
O&M costs ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Ops & maint.	-	-	-	2,843	2,928	3,016	3,107	3,200	3,296	3,395	3,496	3,601	3,709
Wheeling costs	-	-	-	569	586	603	621	640	659	679	699	720	742
Offset power purchases ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Offset purchases	-	-	-	8,529	8,785	9,048	9,320	9,599	9,887	10,184	10,489	10,804	11,128
Results ($000)													
Project costs													
Capital amortization			1,453	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278
O&M			-	2,843	2,928	3,016	3,107	3,200	3,296	3,395	3,496	3,601	3,709
Wheeling			-	569	586	603	621	640	659	679	699	720	742
Total costs			1,453	5,690	5,792	5,898	6,006	6,118	6,233	6,352	6,474	6,600	6,730
Project "revenues" (offset of power purchases)			-	8,529	8,785	9,048	9,320	9,599	9,887	10,184	10,489	10,804	11,128
Net project revenues (costs)			(1,453)	2,839	2,993	3,151	3,314	3,481	3,654	3,832	4,015	4,204	4,399
Net present value	$31,300												

...evaluation continues to 2026

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total capital cost $000															
Project phase	Ops.	Ops.	Ops.	Ops.	Ops.	closed	closed	closed	closed	closed	closed	closed	closed	closed	closed
Operating year	11	12	13	14	15	closed	closed	closed	closed	closed	closed	closed	closed	closed	closed
Capital cost amortization ($000)															
Amortization period	P&I	P&I	P&I	P&I	P&I	done	done	done	done	done	done	done	done	done	done
Amount	2,278	2,278	2,278	2,278	2,278	-	-	-	-	-	-	-	-	-	-
Power generated, 000 MWh	173	173	173	173	173	-	-	-	-	-	-	-	-	-	-
O&M costs ($000)															
Inflation factor	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Ops & maint.	3,821	3,935	4,053	4,175	4,300	-	-	-	-	-	-	-	-	-	-
Wheeling costs	764	787	811	835	860	-	-	-	-	-	-	-	-	-	-
Offset power purchases ($000)															
Inflation factor	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Offset purchases	11,462	11,806	12,160	12,525	12,901	-	-	-	-	-	-	-	-	-	-
Results ($000)															
Project costs															
Capital amortization	2,278	2,278	2,278	2,278	2,278	-	-	-	-	-	-	-	-	-	-
O&M	3,821	3,935	4,053	4,175	4,300	-	-	-	-	-	-	-	-	-	-
Wheeling	764	787	811	835	860	-	-	-	-	-	-	-	-	-	-
Total costs	6,863	7,001	7,142	7,288	7,439	-	-	-	-	-	-	-	-	-	-
Project "revenues" (offset of power purchases)	11,462	11,806	12,160	12,525	12,901	-	-	-	-	-	-	-	-	-	-
Net project revenues (costs)	4,599	4,805	5,018	5,237	5,462	-	-	-	-	-	-	-	-	-	-

Table A-3

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
High Electricity Market Value

This spreadsheet evaluates the preliminary high electricity value feasibility of generating electricity from landfill gas at the Cedar Hills Landfill.

Sensitivity case 1 assumptions are provided in Tables 5-1

Assumptions

Capacity of LFG facility, MWe		22	
Annual availability of LFG system, percent		90%	(= plant capacity factor)
Wheeling cost, cents/kWh		0.30	
Capital cost of LFG to energy system, thousands 1999$		20,000	
Unit cost of system, $million/MW capacity:	0.90		
Capital cost of utility system intertie, thousands 1999$		750	
Operating period, years		15	
Amortization of LFG system and intertie capital cost			
Years		15	
Interest rate		7.0%	
LFG-to-energy plant ops & maint cost, cents/kWh		1.50	
Value of offset power purchases, cents/kWh		6.50	
Rate of inflation			
For operations & maint costs, wheeling costs		3.0%	
For value of offset power purchases		3.0%	
Discount rate for computing net present value		7.0%	

Assume project becomes operational January 2002
Evaluate annual average production only, not hour-by-hour generation and resulting hour-by-hour offset of power purchases, including peak period impacts.
Assume there is sufficient LFG to produce 22 MWe consistently.
Assume there is sufficient demand at the WWTP to consume 22 MWe consistently.
Assume no tax credits or other tax impacts.
Assume use of existing LFG collection system, and that operations and maintenance costs of that system are the same whether flaring the LFG or operating the LFG-to-energy plant.
Assume no credit for offset in flare O&M costs.

Net present value (cost) with the above assumptions, $000: *$69,900*
(see calculations on next page to see how this was derived)

Table A-4

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
High Electricity Market Value

Calculations

Year		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total capital cost $000	20,750												
Project phase		Design/permit	Const.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.
Operating year				1	2	3	4	5	6	7	8	9	10
Capital cost amortization ($000)													
Amortization period			Interest only	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I
Amount			1,453	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278
Power generated, 000 MWh	-	-	-	173	173	173	173	173	173	173	173	173	173
O&M costs ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Ops & maint.	-	-	-	2,843	2,928	3,016	3,107	3,200	3,296	3,395	3,496	3,601	3,709
Wheeling costs	-	-	-	569	586	603	621	640	659	679	699	720	742
Offset power purchases ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Offset purchases	-	-	-	12,320	12,689	13,070	13,462	13,866	14,282	14,710	15,151	15,606	16,074
Results ($000)													
Project costs													
Capital amortization			1,453	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278	2,278
O&M			-	2,843	2,928	3,016	3,107	3,200	3,296	3,395	3,496	3,601	3,709
Wheeling			-	569	586	603	621	640	659	679	699	720	742
Total costs			1,453	5,690	5,792	5,898	6,006	6,118	6,233	6,352	6,474	6,600	6,730
Project "revenues" (offset of power purchases)			-	12,320	12,689	13,070	13,462	13,866	14,282	14,710	15,151	15,606	16,074
Net project revenues (costs)			(1,453)	6,630	6,897	7,172	7,456	7,748	8,049	8,358	8,677	9,006	9,345
Net present value	$69,900												

...evaluation continues to 2026

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total capital cost $000															
Project phase	Ops.	Ops.	Ops.	Ops.	Ops.	closed	closed	closed	closed	closed	closed	closed	closed	closed	closed
Operating year	11	12	13	14	15	closed	closed	closed	closed	closed	closed	closed	closed	closed	closed
Capital cost amortization ($000)															
Amortization period	P&I	P&I	P&I	P&I	P&I	done	done	done	done	done	done	done	done	done	done
Amount	2,278	2,278	2,278	2,278	2,278	-	-	-	-	-	-	-	-	-	-
Power generated, 000 MWh	173	173	173	173	173	-	-	-	-	-	-	-	-	-	-
O&M costs ($000)															
Inflation factor	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Ops & maint.	3,821	3,935	4,053	4,175	4,300	-	-	-	-	-	-	-	-	-	-
Wheeling costs	764	787	811	835	860	-	-	-	-	-	-	-	-	-	-
Offset power purchases ($000)															
Inflation factor	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Offset purchases	16,556	17,053	17,565	18,092	18,634	-	-	-	-	-	-	-	-	-	-
Results ($000)															
Project costs															
Capital amortization	2,278	2,278	2,278	2,278	2,278	-	-	-	-	-	-	-	-	-	-
O&M	3,821	3,935	4,053	4,175	4,300	-	-	-	-	-	-	-	-	-	-
Wheeling	764	787	811	835	860	-	-	-	-	-	-	-	-	-	-
Total costs	6,863	7,001	7,142	7,288	7,439	-	-	-	-	-	-	-	-	-	-
Project "revenues" (offset of power purchases)	16,556	17,053	17,565	18,092	18,634	-	-	-	-	-	-	-	-	-	-
Net project revenues (costs)	9,693	10,052	10,422	10,803	11,196	-	-	-	-	-	-	-	-	-	-

Table A-5

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
High Capital/O&M Cost

This spreadsheet evaluates the preliminary Sensitivity Case 2 feasibility of generating electricity from landfill gas at the Cedar Hills Landfill and wheeling the power to the County's Renton wastewater treatment facility to offset power purchased there from Puget Sound Energy.

Sensitivity Case 2 assumptions are listed on Table 5-1

Assumptions

Capacity of LFG facility, MWe		22	
Annual availability of LFG system, percent		90%	(= plant capacity factor)
Wheeling cost, cents/kWh		0.30	
Capital cost of LFG to energy system, thousands 1999$		24,000	
Unit cost of system, $million/MW capacity:	1.10		
Capital cost of utility system intertie, thousands 1999$		750	
Operating period, years		15	
Amortization of LFG system and intertie capital cost			
Years		15	
Interest rate		7.0%	
LFG-to-energy plant ops & maint cost, cents/kWh		1.80	
Value of offset power purchases, cents/kWh		4.50	
Rate of inflation			
For operations & maint costs, wheeling costs		3.0%	
For value of offset power purchases		3.0%	
Discount rate for computing net present value		7.0%	

Assume project becomes operational January 2002
Evaluate annual average production only, not hour-by-hour generation and resulting hour-by-hour offset of power purchases, including peak period impacts.
Assume there is sufficient LFG to produce 22 MWe consistently.
Assume there is sufficient demand at the WWTP to consume 22 MWe consistently.
Assume no tax credits or other tax impacts.
Assume use of existing LFG collection system, and that operations and maintenance costs of that system are the same whether flaring the LFG or operating the LFG-to-energy plant.
Assume no credit for offset in flare O&M costs.

Net present value (cost) with the above assumptions, $000: *$21,500*
(see calculations on next page to see how this was derived)

Table A-6

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
High Capital O&M Costs

Calculations

…evaluation continues to 2026

Year		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total capital cost $000	24,750												
Project phase	Design/permit		Const.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.
Operating year				1	2	3	4	5	6	7	8	9	10
Capital cost amortization ($000)													
Amortization period			Interest only	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I
Amount			1,733	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717
Power generated, 000 MWh	-	-	-	173	173	173	173	173	173	173	173	173	173
O&M costs ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Ops & maint.	-	-	-	3,412	3,514	3,619	3,728	3,840	3,955	4,074	4,196	4,322	4,451
Wheeling costs	-	-	-	569	586	603	621	640	659	679	699	720	742
Offset power purchases ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Offset purchases	-	-	-	8,529	8,785	9,048	9,320	9,599	9,887	10,184	10,489	10,804	11,128
Results ($000)													
Project costs													
Capital amortization			1,733	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717
O&M			-	3,412	3,514	3,619	3,728	3,840	3,955	4,074	4,196	4,322	4,451
Wheeling			-	569	586	603	621	640	659	679	699	720	742
Total costs			1,733	6,698	6,817	6,940	7,067	7,197	7,332	7,470	7,613	7,759	7,911
Project "revenues" (offset of power purchases)			-	8,529	8,785	9,048	9,320	9,599	9,887	10,184	10,489	10,804	11,128
Net project revenues (costs)			(1,733)	1,831	1,968	2,108	2,253	2,402	2,556	2,714	2,877	3,045	3,218
Net present value	$21,500												

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Project phase	Ops.	Ops.	Ops.	Ops.	Ops.	closed	closed	closed	closed	closed	closed	closed	closed	closed	closed
Operating year	11	12	13	14	15	closed	closed	closed	closed	closed	closed	closed	closed	closed	closed
Amortization period	P&I	P&I	P&I	P&I	P&I	done	done	done	done	done	done	done	done	done	done
Amount	2,717	2,717	2,717	2,717	2,717	-	-	-	-	-	-	-	-	-	-
Power generated, 000 MWh	173	173	173	173	173	-	-	-	-	-	-	-	-	-	-
O&M Inflation factor	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Ops & maint.	4,585	4,722	4,864	5,010	5,160	-	-	-	-	-	-	-	-	-	-
Wheeling costs	764	787	811	835	860	-	-	-	-	-	-	-	-	-	-
Offset Inflation factor	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Offset purchases	11,462	11,806	12,160	12,525	12,901	-	-	-	-	-	-	-	-	-	-
Capital amortization	2,717	2,717	2,717	2,717	2,717	-	-	-	-	-	-	-	-	-	-
O&M	4,585	4,722	4,864	5,010	5,160	-	-	-	-	-	-	-	-	-	-
Wheeling	764	787	811	835	860	-	-	-	-	-	-	-	-	-	-
Total costs	8,066	8,227	8,392	8,562	8,738	-	-	-	-	-	-	-	-	-	-
Project "revenues" (offset of power purchases)	11,462	11,806	12,160	12,525	12,901	-	-	-	-	-	-	-	-	-	-
Net project revenues (costs)	3,396	3,579	3,768	3,963	4,163	-	-	-	-	-	-	-	-	-	-

Table A-7

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
Extended Operating Period (20 yrs)

This spreadsheet evaluates the preliminary Sensitivity Case 2 feasibility of generating electricity from landfill gas at the Cedar Hills Landfill and wheeling the power to the County's Renton wastewater treatment facility to offset power purchased there from Puget Sound Energy.

Sensitivity Case 2 assumptions are listed on Table 5-1

Assumptions

Capacity of LFG facility, MWe		22	
Annual availability of LFG system, percent		90%	(= plant capacity factor)
Wheeling cost, cents/kWh		0.30	
Capital cost of LFG to energy system, thousands 1999$		20,000	
Unit cost of system, $million/MW capacity:	0.90		
Capital cost of utility system intertie, thousands 1999$		750	
Operating period, years		20	
Amortization of LFG system and intertie capital cost			
Years		20	
Interest rate		7.0%	
LFG-to-energy plant ops & maint cost, cents/kWh		1.50	
Value of offset power purchases, cents/kWh		4.50	
Rate of inflation			
For operations & maint costs, wheeling costs		3.0%	
For value of offset power purchases		3.0%	
Discount rate for computing net present value		7.0%	

Assume project becomes operational January 2002
Evaluate annual average production only, not hour-by-hour generation and resulting hour-by-hour offset of power purchases, including peak period impacts.
Assume there is sufficient LFG to produce 22 MWe consistently.
Assume there is sufficient demand at the WWTP to consume 22 MWe consistently.
Assume no tax credits or other tax impacts.
Assume use of existing LFG collection system, and that operations and maintenance costs of that system are the same whether flaring the LFG or operating the LFG-to-energy plant.
Assume no credit for offset in flare O&M costs.

Net present value (cost) with the above assumptions, $000: *$43,000*
(see calculations on next page to see how this was derived)

Table A-8

King County Department of Natural Resources, Solid Waste Division
Landfill Gas Fired Generation Feasibility Evaluation
Extended Operating Period (20 yr)

Calculations

…operations continue to 2021
…evaluation continues to 2026

Year		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total capital cost $000	20,750												
Project phase		Design/permit	Const.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.
Operating year				1	2	3	4	5	6	7	8	9	10
Capital cost amortization ($000)													
Amortization period			Interest only	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I
Amount			1,453	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959
Power generated, 000 MWh	-	-	-	173	173	173	173	173	173	173	173	173	173
O&M costs ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Ops & maint.	-	-	-	2,843	2,928	3,016	3,107	3,200	3,296	3,395	3,496	3,601	3,709
Wheeling costs	-	-	-	569	586	603	621	640	659	679	699	720	742
Offset power purchases ($000)													
Inflation factor	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43
Offset purchases	-	-	-	8,529	8,785	9,048	9,320	9,599	9,887	10,184	10,489	10,804	11,128
Results ($000)													
Project costs													
Capital amortization			1,453	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959
O&M			-	2,843	2,928	3,016	3,107	3,200	3,296	3,395	3,496	3,601	3,709
Wheeling			-	569	586	603	621	640	659	679	699	720	742
Total costs			1,453	5,370	5,473	5,578	5,687	5,798	5,914	6,032	6,154	6,280	6,410
Project "revenues" (offset of power purchases)			-	8,529	8,785	9,048	9,320	9,599	9,887	10,184	10,489	10,804	11,128
Net project revenues (costs)			(1,453)	3,159	3,312	3,470	3,633	3,801	3,974	4,152	4,335	4,524	4,718
Net present value	$43,000												

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Project phase	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	Ops.	closed	closed	closed	closed	closed
Operating year	11	12	13	14	15	16	17	18	19	20	closed	closed	closed	closed	closed
Amortization period	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	P&I	done	done	done	done	done
Amount	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	-	-	-	-	-
Power generated, 000 MWh	173	173	173	173	173	173	173	173	173	173	-	-	-	-	-
Inflation factor (O&M)	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Ops & maint.	3,821	3,935	4,053	4,175	4,300	4,429	4,562	4,699	4,840	4,985	-	-	-	-	-
Wheeling costs	764	787	811	835	860	886	912	940	968	997	-	-	-	-	-
Inflation factor (Offset)	1.47	1.51	1.56	1.60	1.65	1.70	1.75	1.81	1.86	1.92	1.97	2.03	2.09	2.16	2.22
Offset purchases	11,462	11,806	12,160	12,525	12,901	13,288	13,686	14,097	14,520	14,955	-	-	-	-	-
Capital amortization	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	1,959	-	-	-	-	-
O&M	3,821	3,935	4,053	4,175	4,300	4,429	4,562	4,699	4,840	4,985	-	-	-	-	-
Wheeling	764	787	811	835	860	886	912	940	968	997	-	-	-	-	-
Total costs	6,544	6,681	6,823	6,969	7,119	7,274	7,433	7,597	7,767	7,941	-	-	-	-	-
Project "revenues" (offset of power purchases)	11,462	11,806	12,160	12,525	12,901	13,288	13,686	14,097	14,520	14,955	-	-	-	-	-
Net project revenues (costs)	4,919	5,125	5,337	5,556	5,782	6,014	6,253	6,500	6,753	7,015	-	-	-	-	-